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(54) **Apparatus for measuring pressure**

(57) Apparatus for combining two measurements of pressure, one measurement being obtained from a first pressure gauge 1 having good long-term stability and a second being obtained from a second gauge 2 having good dynamic response, comprises signal processing means 3 to provide a single measurement with good long-term stability and good dynamic response. In the apparatus shown, the second pressure gauge 2 is an optical pressure gauge 24 used to measure downhole pressure (communicated via a device 30) in a gas or oil well 20, and connected to a display 26 and the processor 3 by a cable 25. The cable passes to the surface through a narrowbore hydraulic conduit 27, and the gauge and cable may be put in place by being pumped through the conduit. The surface end of the conduit 27 is connected to the first gauge 1 which measures the surface pressure, related to the downhole pressure by the weight of fluid in the conduit. The arrangement allows the first gauge 1 to be used in periodic checks for drift in the response of the downhole gauge whereupon a suitable correction may be applied. A number of refinements are described.

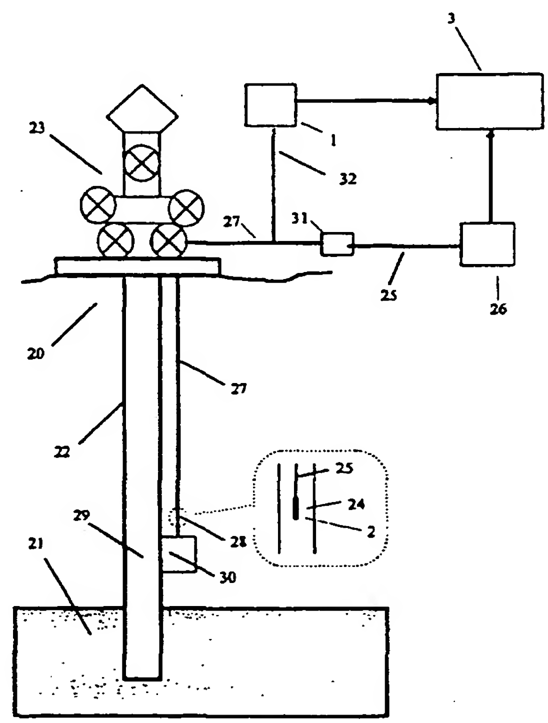

Figure 2

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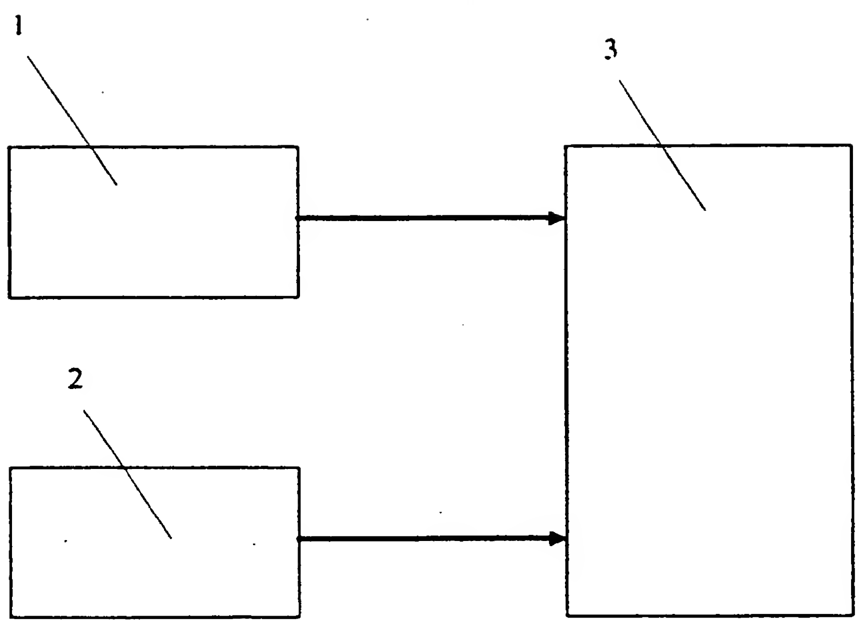

Figure 1

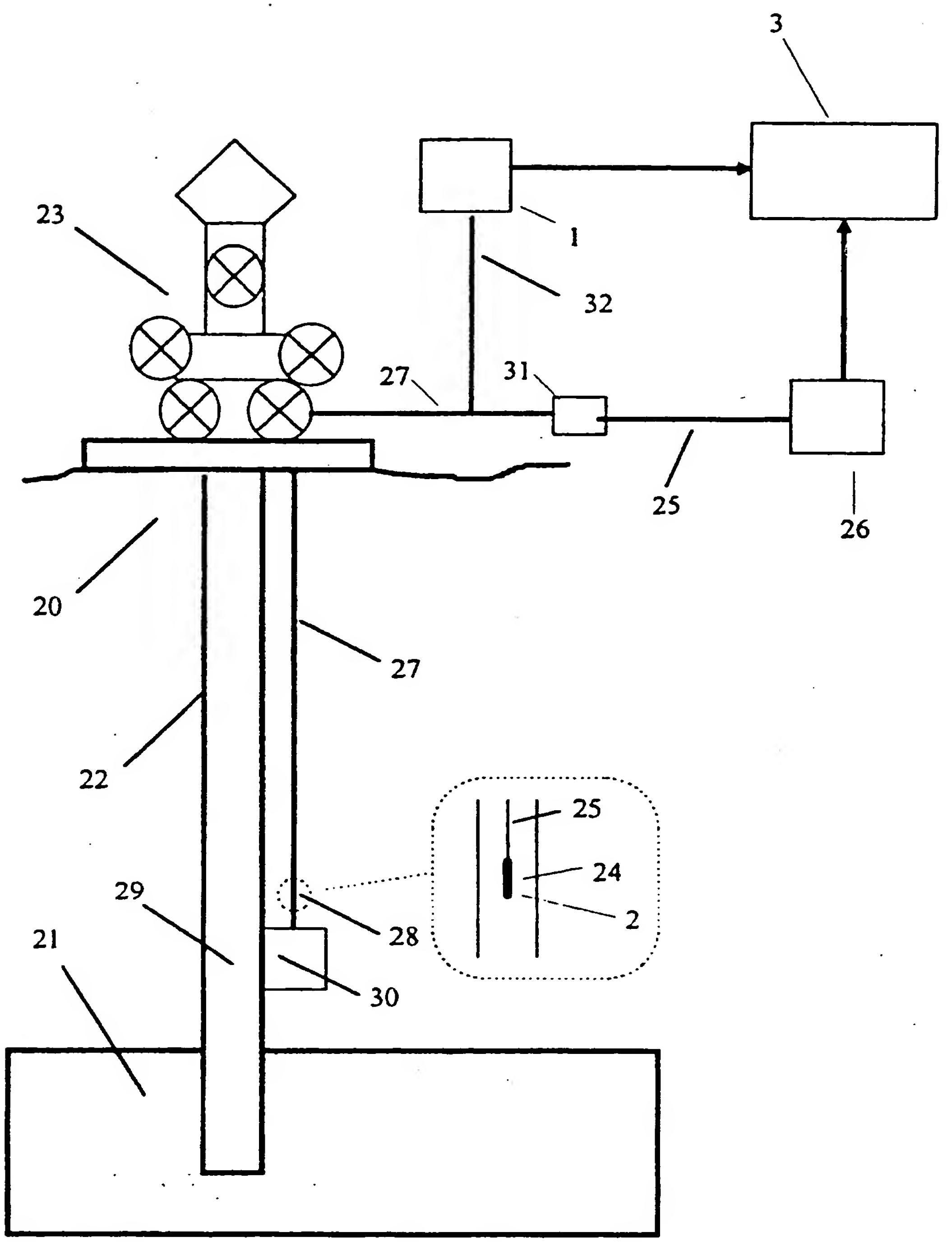

Figure 2

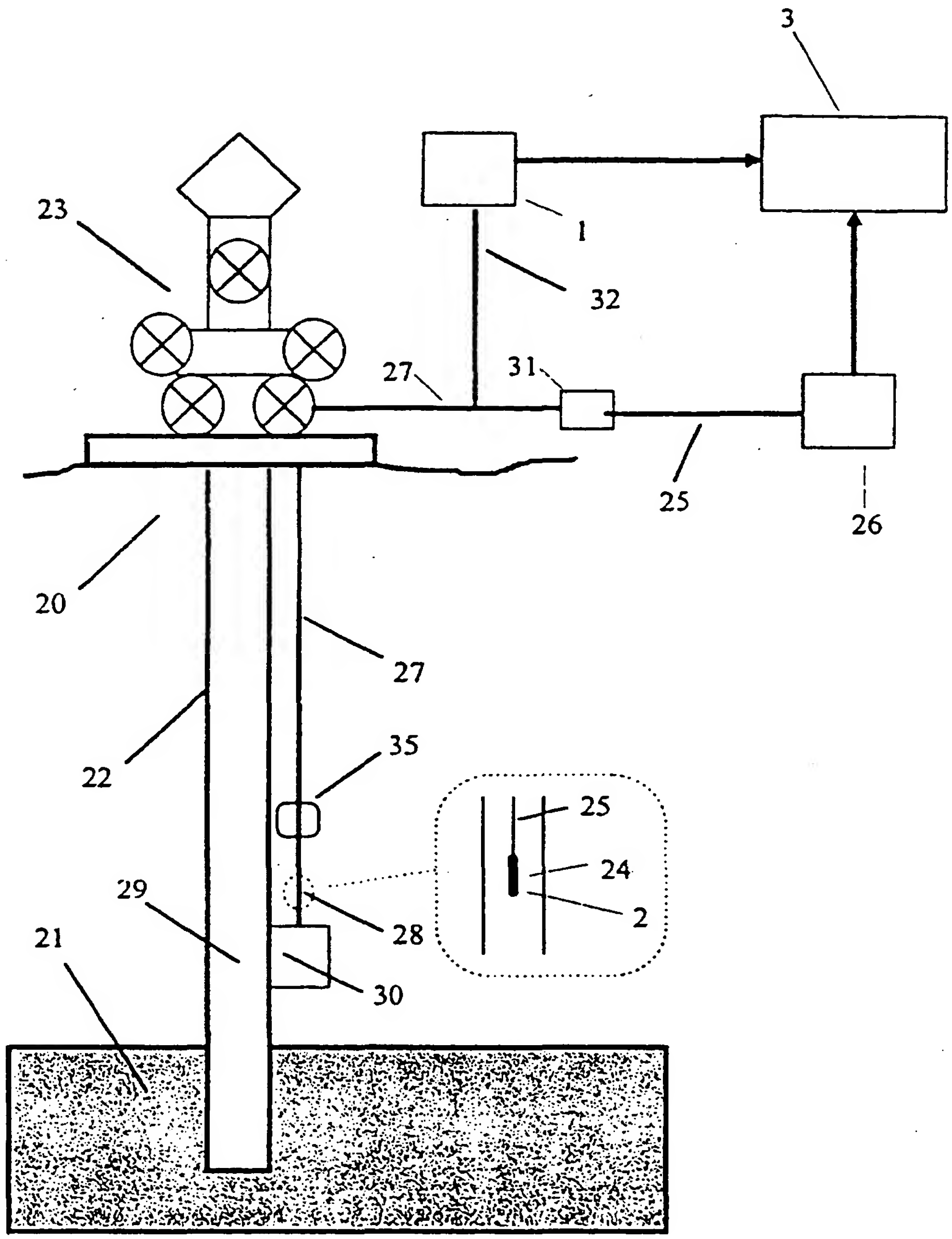

Figure 3

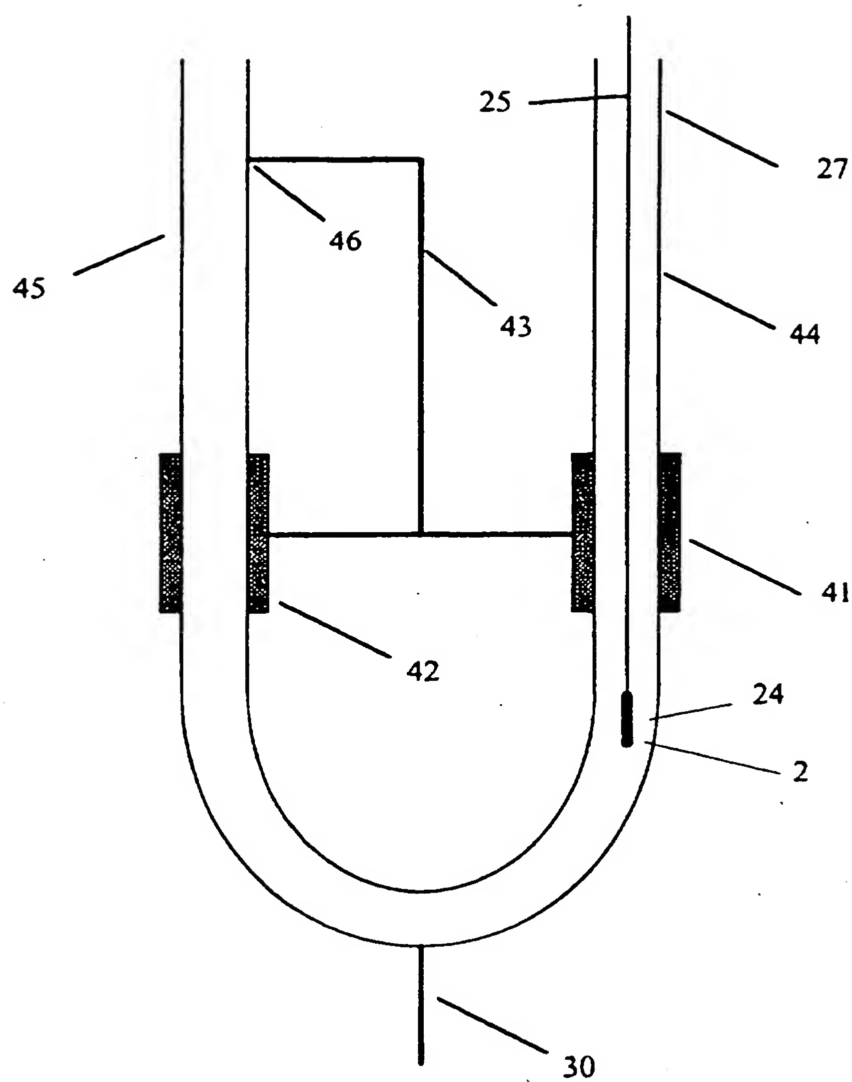

Figure 4

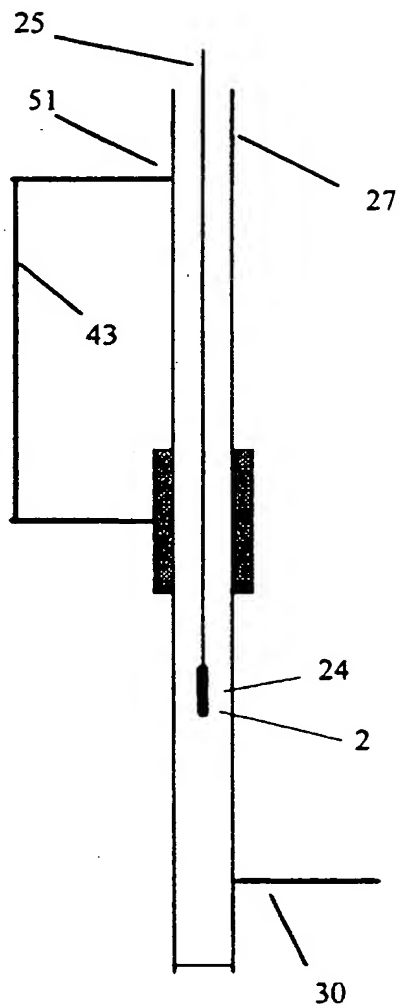

Figure 5

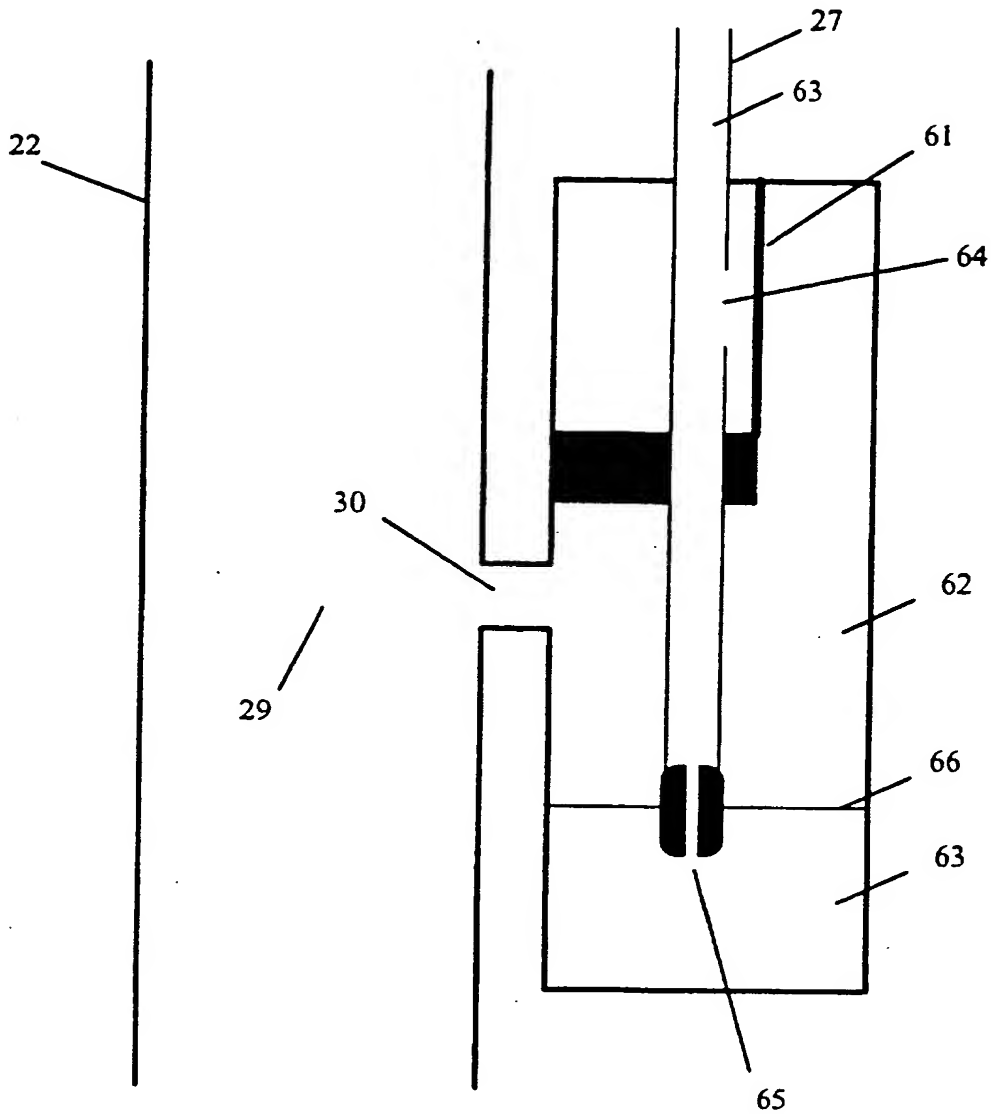

Figure 6

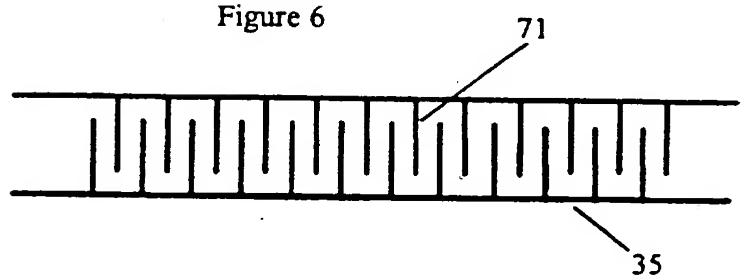

Figure 7

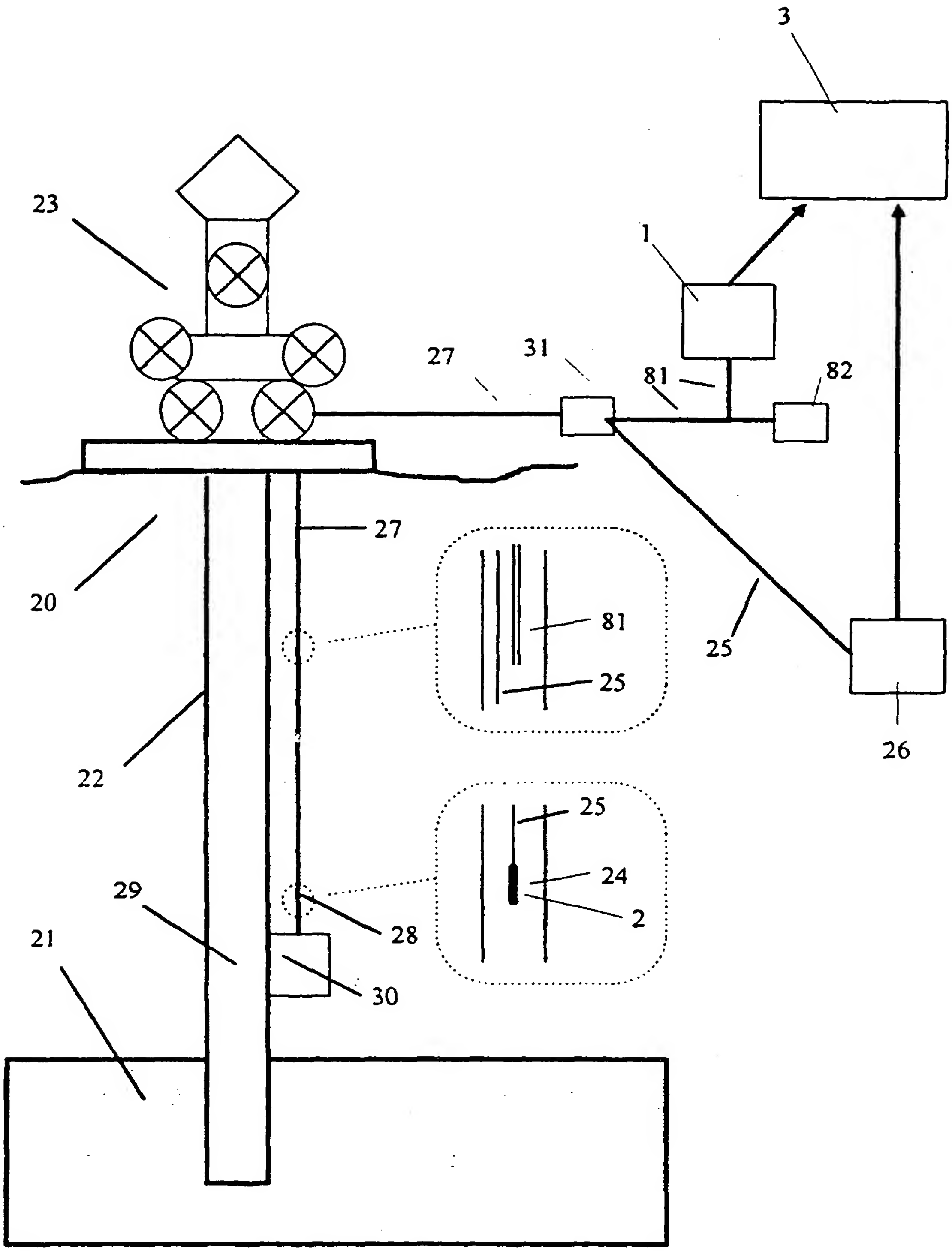

Figure 8

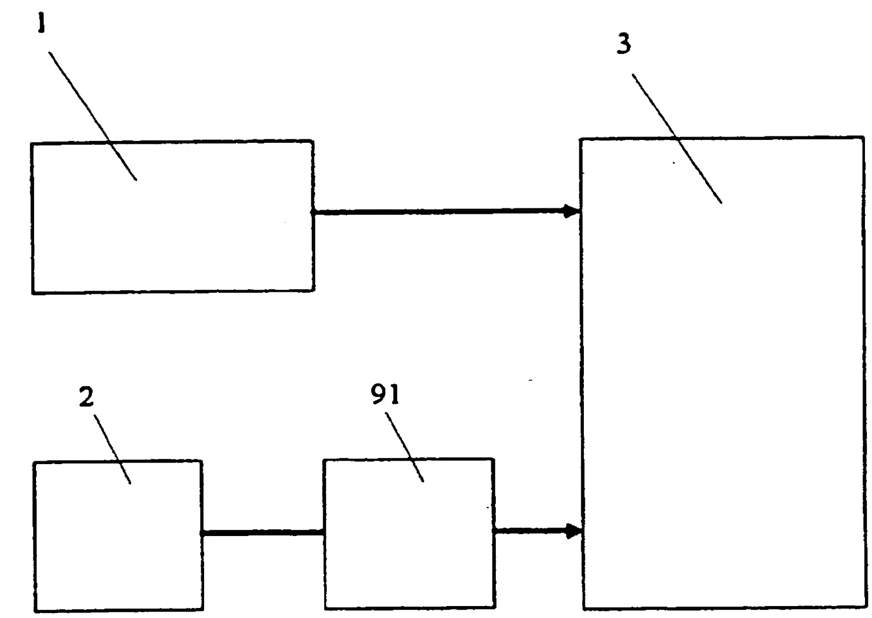

Figure 9

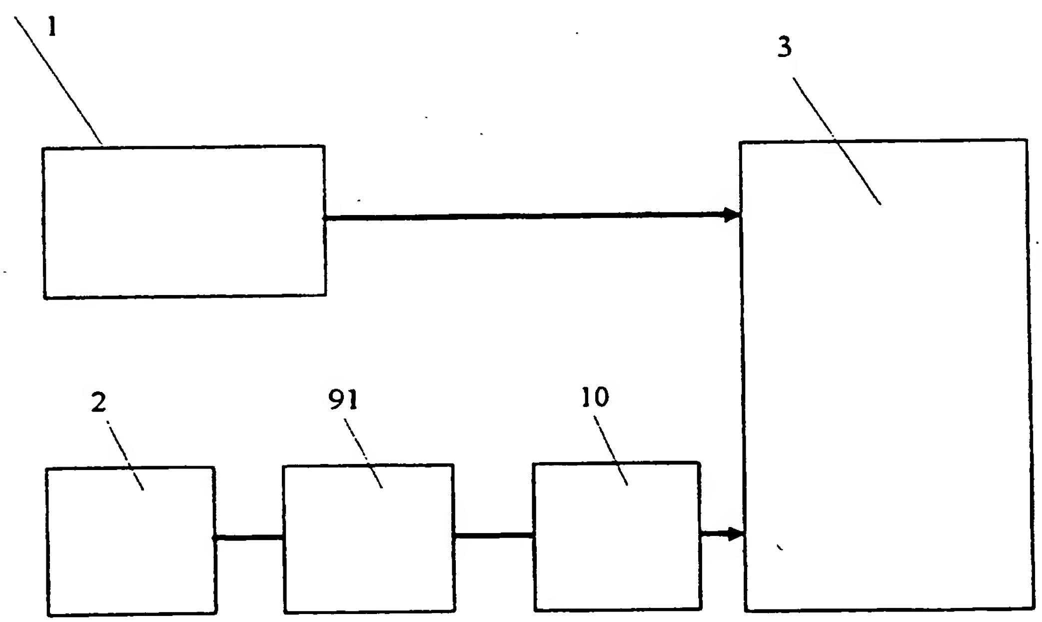

Figure 10

APPARATUS FOR MEASURING PRESSURE

The invention relates to apparatus for measuring pressure in remote locations. The invention is particularly relevant in the oil and gas industries for calibrating permanent downhole gauges.

As oil and gas reserves have been consumed over the years, the extraction of the oil and gas reserves has become increasingly more difficult under more demanding conditions. Accordingly, there is a need for more information and better quality information about the reservoir, and this is particularly so for oil and gas reserves which lie beneath the sea bed. Optical fibre sensors, together with optical fibre cables to link the sensor to the measurement instrumentation, are being developed for this purpose since they offer specific advantages, particularly in the ability to withstand extremes of high pressure and temperature. Furthermore, such optical fibre sensors may be of a structure and diameter similar to those of the optical fibre cable itself. Sensors are being developed which can be remotely deployed into oil and gas wells through conveniently sized and commonly used hydraulic tubing.

One of the sensors being developed is a pressure sensor which can be remotely deployed through conveniently sized hydraulic tubing in order to measure downhole pressure. The pressure can be communicated from say the inside of the production tubing through which oil flows to the surface by means of a pressure

communicating port which communicates pressure say from the production tubing to the inside of the hydraulic tubing where the downhole pressure sensor is located.

Pressure can also be communicated through the hydraulic tubing from the surface end to the downhole end and vice versa, and this allows the downhole pressure sensor to be calibrated using pressure gauges at the surface which can be easily replaced or themselves calibrated. This feature removes the requirement for ultra-low drift over many years from the downhole pressure sensor since drift can readily be removed using the gauge at the surface. Unfortunately, it is not possible to dispense with the downhole pressure gauge because of the dispersive properties of a long section of hydraulic tubing. Thus the hydraulic tubing does not transmit faithfully dynamic pressure information with high resolution. In essence, this implies that the gauge at the surface can only provide the correct measurement for slowly varying pressures with an effective time constant of minutes to hours, while the downhole gauge can provide an accurate measurement of pressure. Unfortunately, the environment for the downhole gauge can be severe which can lead to the downhole pressure gauge drifting. It is therefore desirable that the two measures of pressure be combined into one measurement of pressure where the potential drift of the downhole pressure gauge is removed while retaining the dynamic information from the downhole measurement.

Techniques to communicate the downhole pressure to the surface via capillaries have been in existence for many years. An important category of

instruments (bubblers) use metal capillaries of inner-diameter 1mm to 5mm through which gases are flowed into the production tubing of oil wells. The surface pressure on the capillary which causes gas to bubble into the well is a measure of the bottom hole pressure. It is known that this pressure can be corrected with the temperature profile along the production string which can be measured using a temperature profiling sensor. A related technique uses a downhole chamber which serves to keep the interface between the produced fluid and the pressure communicating gas column inside this chamber and away from the capillary. The gas is pressurised at the surface with a pressure sufficient to maintain the liquid interface in the chamber during the lifetime of the measurement. Both these techniques have drawbacks: neither technique is appropriate for horizontal wells or high-pressure gas wells; the weight of the gas in the column creates inaccuracies when communicating pressures over the very long lengths (>2km), and the capillary can become blocked by the ingress of produced fluid (oil, gas and water mixtures). If the capillary becomes blocked or otherwise damaged, it prevents measurements of downhole pressure without ceasing production, pulling up the production tubing onto which the capillary is typically strapped, repairing or replacing the tubing, and then lowering production tubing back into the well. The economic cost of doing this is extremely high. These systems have a drawback of being unable to communicate rapidly varying pressure information up long lengths of the capillary tubing without distorting the information. Transient behaviour of pressure such as occurs during

well testing can therefore not be accurately measured. This information is considered of importance by reservoir engineers for establishing a model of the reservoir. In addition, there is an important safety issue when measuring the pressure in high-pressure gas wells in that the capillary tubing at the surface is exposed to the high pressure.

An aim of the present invention is to combine two separate measurements of pressure, one measurement carried out at or near the surface and having a very-low drift, and the other measurement being carried out by the downhole sensor and having excellent dynamic response, repeatability, and resolution, but accompanied by the potential for drift which may be caused by exposure of the sensor to high temperatures and complex chemicals. Combining the two measurements in a signal processing unit can result in the overall information being of high quality and not suffering from either drift or insufficient dynamic information.

A further aim is to improve on known techniques for pressure measurement using bubblers by ensuring that the pressure within the capillary is maintained at an acceptable level when used in high-pressure gas wells. This is achieved by using a smaller capillary tube interfacing into a hydraulic control line which contains a column of buffering liquid of controlled quality.

A further aim is to improve on known techniques for pressure measurement using bubblers by adding the capability of replacing the capillary simply in the event

that it becomes damaged or blocked, without requiring an interruption to normal oil production.

A further aim is to improve on known techniques for pressure measurement by including one or more flow restrictors which prevent produced fluids from moving up the hydraulic tubing during the potentially large pressure surges which can occur in well testing. Significant flow rates in such circumstances can cause movement of the downhole pressure sensor and can cause further inaccuracies due to associated pressure gradients along the hydraulic tubing between the production string and the downhole pressure sensor. If such downhole flow restrictors are located near the pressure communicating port then it is no longer necessary to have the relatively large fluid buffer chamber which is a feature of some bubbler systems.

According to a non-limiting embodiment of the present invention, there is provided apparatus for combining measurements of pressure where one measurement is obtained from a first pressure gauge having good long-term stability and a second pressure gauge having good dynamic response where the two measurements are combined in a signal processing means to provide a single measurement with good long-term stability and good dynamic response. For downhole oil industry applications, good long-term stability may be a long term accuracy of around 1psi per year, whereas good dynamic response may involve being able to track a pressure transient of around 1000psi in ten seconds to an

accuracy of 1psi while also being able to resolve pressure changes of 0.01psi to 0.1psi.

In the first embodiment of the present invention, the second pressure gauge is an optical pressure gauge where the optical pressure gauge and its associated cable interconnecting the optical pressure gauge with its associated readout electronics is of suitable dimensions to be pumped with fluid through a narrowbore conduit means to a remote location and where pressure is communicated from a measurement location to the optical pressure gauge via a pressure communication means. The narrowbore conduit means may be standard steel hydraulic tubing of ¼" outside diameter.

In the second embodiment of the invention there is also provided a flow preventor means to restrict fluid from the measurement location flowing into the narrowbore conduit means.

This embodiment is of particular importance in an oil well where pressure gauges are used for characterising the reservoir. This characterisation often involves so-called "shut-in tests" where the surface valves controlling the flow of fluids up the production tubing are closed. This induces a rise in the pressure within the production tubing. The purpose of the flow preventor means in this example is to prevent, or minimise the oil from flowing into the narrowbore conduit means while measuring the downhole pressure.

The flow preventor means may contain a valve means and a second conduit means, where the second conduit means interconnects between the valve means and the narrowbore conduit means, and where the valve means is closed when the pressure in the second conduit means is sufficient to close the valve means. This may be achieved when the pressure drop between the interconnection between the narrowbore conduit means and the second conduit means is greater along the second conduit means than in the narrowbore conduit means.

The flow preventor means may contain a diaphragm means buffering the fluid in the measurement location from the fluid in the narrowbore conduit means, and where there is sufficient fluid in the diaphragm means to pressurise the narrowbore conduit means during a pressure build up in the measurement location, and where there is an orifice means interconnecting the measurement location and the narrowbore conduit means to communicate the pressure accurately during slow pressure changes.

The flow preventor means may contain baffles which induce higher pressure drops for the same flow rate thus allowing faithful pressure communication and assisting the ability to flush contaminants such as oil out of the flow preventor means when required.

According to another embodiment of the current invention, the apparatus contains a capillary means which interconnects a measurement point within the narrowbore conduit means and the first pressure gauge, and where gas is injected

through the capillary means according to the well-known bubbler principle. An important difference between this embodiment and bubblers is that the capillary means terminates in the narrowbore conduit means which may be a considerable distance from the remote location. This has the advantage when measuring pressures in high-pressure gas or oil wells in that the narrowbore conduit means can be filled with fluid of controlled quality, hence significantly reducing the risk of blockage of the capillary, and also potentially reducing the pressure rating requirement of the capillary means.

The capillary means may be of sufficient dimensions to be pumped along the narrowbore conduit means.

The capillary means may resemble a silica optical fibre. Suitable dimensions for the capillary means may comprise a coated outer diameter less than 2.5mm, a glass outer diameter less than 250µm and an inner diameter of greater than 25µm. A typical design would have an outer diameter of 150µm, a glass outer diameter of 125µm and an inner diameter of 75µm. Similar capillaries have found acceptance in high-pressure chromatography.

The signal processing means may comprise a filter for removing the low frequency content from the second pressure gauge, and a summer for adding the resulting signal to the signal from the first pressure gauge.

The signal processing means may further include a delay element for delaying the filtered signal from the second pressure gauge by an amount

approximately equal to the time delay between a pressure change affecting the second pressure gauge and the first pressure gauge.

Embodiments of the invention will now be described solely by way of example and with reference to the accompanying drawings in which:

Figure 1 is a diagram of an embodiment of the present invention in which a signal processing means processes information from a first pressure gauge and a second pressure gauge;

Figure 2 is a diagram of an embodiment of the present invention where the second pressure gauge is an optical pressure gauge;

Figure 3 is a diagram of an embodiment of the present invention which includes a flow restrictor means;

Figure 4 is a diagram of an embodiment of the flow restrictor means which uses two valve means;

Figure 5 is a diagram of an embodiment of the flow restrictor means which uses a single valve means;

Figure 6 is a diagram of an embodiment of the flow restrictor means which uses an orifice means and a diaphragm means;

Figure 7 is a diagram of an embodiment of the flow restrictor means which contains baffles;

Figure 8 is a diagram of an embodiment of the present invention incorporating a capillary means;

Figure 9 is a diagram of an embodiment of the signal processing means including a filter means and a summer; and

Figure 10 is a diagram of an embodiment of the signal processing means including a delay element.

With reference to Figure 1, there is provided apparatus for combining measurements of pressure where one measurement is obtained from a first pressure gauge 1 having good long-term stability and a second pressure gauge 2 having good dynamic response where the two measurements are combined in a signal processing means 3 to provide a single measurement with good long-term stability and good dynamic response.

For downhole oil industry applications, good long-term stability may be a long term accuracy of around 1psi per year, whereas good dynamic response may involve being able to track a pressure transient of around 1000psi in ten seconds to an accuracy of 1psi while also being able to resolve pressure changes of 0.1psi or less. It is beneficial if the first pressure gauge 1 and the second pressure gauge 2 can be calibrated when required. Such a calibration may involve periodically comparing the output of one gauge with respect to the other, and estimating the offset and drift of the second pressure gauge 2. These parameters can be input into a simple prediction algorithm to allow feed forward compensation of the first pressure gauge 1 in the signal processing means 3 which may be a computer. Thus for example, if it were known that the drift rate of the second pressure gauge 2 was

5psi per month to an accuracy of 0.1psi per month, then it would be possible to simply add an offset to the output of the second pressure gauge 2 corresponding to 5psi multiplied by the number of months following the calibration. The first pressure gauge 1 would therefore only be required in the overall system for a confidence check, or when the uncertainty in the overall measurement had grown to unacceptable levels. The first pressure gauge 1 may therefore only be required very occasionally.

Such a measurement is important in the oil and gas industry where downhole gauges may be subject to extremes of temperature and pressure and a changing chemical environment. Separating the requirements of dynamic response and resolution from long-term stability greatly simplifies the engineering challenge associated with the design of the downhole gauge. The separation is because it is possible to communicate the pressure to the surface where it can be measured with good long-term accuracy - albeit with poor dynamic response.

An implementation of the invention is shown in Figure 2 where it is applied to the measurement of downhole pressure in an oil or gas well 20. Produced fluid (oil, gas and water mixtures) from a reservoir 21 flows to the surface via a length of production tubing 22 and a well head 23. The second pressure gauge 2 is an optical pressure gauge 24 where the optical pressure gauge 24 and its associated cable 25 interconnecting the optical pressure gauge 24 with its associated readout electronics 26 is of suitable dimensions to be pumped with fluid through a narrowbore conduit

means 27 to a remote location 28 and where pressure is communicated from a measurement location 29 to the optical pressure gauge 24 via a pressure communication means 30. The associated cable 25 exits the narrowbore conduit means 27 via a seal means 31. The first pressure gauge 1 is interfaced to the narrowbore conduit means via port means 32.

This embodiment has important applications in measuring pressure in oil wells where the narrowbore conduit means 27 may be constructed from commercial, off-the-shelf hydraulic tubing strapped to the outside of the production tubing 22. The optical pressure gauge 24 may be pumped through the hydraulic tubing which interfaces to the fluid in the production tubing 22 via the pressure communication means 30 which may be a valve. The ability to pump the optical pressure gauge 24 to the remote location through the hydraulic tubing is important because it allows the optical pressure gauge 24 to be installed subsequent to the oil well infrastructure being completed. Moreover, if the hydraulic tubing is configured in a U-tube configuration (ie both ends of the U being accessible at the surface), then the optical pressure gauge 24 can be simply pumped out and replaced in the event of failure or degradation of the optical pressure gauge 24 or its associated cable 25, or if any upgrading in performance be desired. The first pressure gauge 1 measures the pressure at the top of the hydraulic tubing. This pressure is related to the downhole pressure by the weight of fluid in the hydraulic tubing. Thus the first pressure gauge

1 can be used to correct for slowly varying errors in the second pressure gauge 2 with the signal processing means 3.

A disadvantage of the system shown in Figure 2 is that produced fluid such as oil can enter into the narrowbore conduit means 27 through the pressure communication means 30 during a well shut-in test where the valves in the well head 23 are closed and the pressure in the production tubing 22 rises accordingly. This is particularly the case for an underpressure well where the pressure in the reservoir 21 is insufficient to support a column of liquid in the narrowbore conduit means 27.

The solution, Figure 3, is to limit the flow of fluid into the narrowbore conduit means 27 using a flow preventor means 35 where the flow preventor means 35 is of such a design that the second pressure gauge 2 is able to measure the pressure in the measurement location 25 via the pressure communication means 30.

Figure 4 shows an implementation of the flow preventor means 35 comprising a first valve means 41, a second valve means 42 and a second conduit means 43. In this example, the narrowbore conduit means 27 is configured in a U comprising first narrowbore conduit means 44 and second narrowbore conduit means 45 joined together. The narrowbore conduit means 27 interfaces to the measurement location 29 (not shown) via the pressure communication means 30 which may be a valve. The second conduit means 43 interconnects between the first valve means 41 and the second valve means 42 and the second narrowbore conduit means 45 at an interconnection means 46. The second valve means 42 closes when

the pressure drop measured from the interconnection means 46 to the second valve means 42 is greater along the second conduit means 43 than in the second narrowbore conduit means 45 by an amount which depends upon the valve design. Similarly, the first valve means 41 closes when the pressure in the second conduit means 43 is greater that the pressure within the channel within the first valve means 41.

The fibre optic pressure gauge 24 and its associated cable 25 can be pumped through the first narrowbore conduit means 44 with fluid (liquid or gas) without closing the first valve means 41 or the second valve means 42. In order to close the first valve means 41 and the second valve means 42, fluid (liquid or gas) can be pumped down the second narrowbore conduit means 45 in the direction of the pressure communication means 30. When the pressure within the second valve means 42 is less than the pressure in the second conduit means 43, the valve means 42 will close, thus sealing the second conduit means. Note, that depending on the particular installation, it may be necessary to flow fluid down both first narrowbore conduit means 44 and the second narrowbore conduit means 45 simultaneously to prevent the fibre optic pressure gauge 24 from being pumped up the first narrowbore conduit means 44. The first valve means 41 and the second valve means 42 isolate the lower part of the narrowbore conduit means 27 from the surface. The installation can be designed such that if the first valve means 41 and the second valve means 42 are closed by pumping liquid, then the relatively small

liquid volume beneath the first valve means 41 and the second valve means 42 prevents any significant fluid flowing into the narrowbore conduit means 27 through the pressure communication means 30. Note that it may be preferable to have the narrowbore conduit means 27 filled with gas at times other than during well testing in order to reduce hermeticity requirements for fibre optic cables.

The first valve means 41 may be a valve which seals completely around the associated cable 25 when the pressure in the second conduit means 43 reaches a pre-set level in comparison to the pressure in the bore of the first valve means 41. The design must be such that the associated cable 25 is not damaged. This can be achieved using a smaller version of an annular valve known in the oil industry for sealing around wires or pipes. The annular valve may be constructed from a polymer, or for high-pressure applications, incorporate metal leaves to prevent the polymer from shearing.

The second valve means 42 may be of a similar construction to the first valve means 41, or may simply be a valve which seals completely at the desired pressure setting. The implementation of the second valve means 42 may be accomplished by other embodiments which prevent upward flow. Such an embodiment might make use of a storm choke principle.

Note that it is advantageous for there to be a pressure differential between the control pressure for the first valve means 41 and the control pressure for the second valve means 42 before these valves close. Note also that the second conduit

means 43 is preferably filled with a fluid of sufficient weight to ensure that the first valve means 41 and the second valve means 42 can close.

The embodiment shown in Figure 4 can be simplified as shown in Figure 5 where there is valve means 51, and where the second conduit means 43 connects with the narrowbore conduit means 27 at the interconnection means 52. This embodiment contains less components, but has the disadvantage over that shown in Figure 4 in that the optical pressure gauge 24 may not be retrieved simply from the narrowbore conduit means 27 by pumping in the reverse direction through the narrowbore conduit means 27.

An alternative implementation of the flow preventor means 35 is shown in Figure 6. The flow preventor means 35 contains a diaphragm means 61 buffering a first fluid 62 in the measurement location 29 from a second fluid 63 in the narrowbore conduit means 27, and where there is sufficient fluid in the diaphragm means 61 to pressurise the narrowbore conduit means 27 during a pressure build up in the measurement location 29 through a side port means 64. There is also provided an orifice means 65 to provide a connection between the measurement location 29 and the narrowbore conduit means 27 such that pressure is communicated accurately during slow pressure changes. In this implementation, large pressure changes (for example 1000psi change over ten seconds) are communicated via the diaphragm means 61, whereas small pressure changes (for example 1psi over ten seconds) are mainly communicated via the orifice means 65.

The orifice means 65 has an exit below the liquid level 66 separating the first conduit fluid 62 and the second conduit fluid 63. In the implementation shown, the second conduit fluid 63 is more dense than the first conduit fluid 62 – but this is not a requirement. The important detail is that the orifice means 65 should be configured to prevent the first conduit fluid 62 from entering the narrowbore conduit means 27 while permitting pressure communication via the orifice means 65 without hysteresis, albeit at a relatively low flow rate. This flow rate would not be sufficient to follow large and rapid pressure changes at the measurement location 29.

The diaphragm means 61 may be constructed as a bellows, or may be of sufficient size and elasticity to allow very rapid pressure changes to be communicated to the narrowbore conduit means 27.

It will be appreciated that it may be necessary to pump fluid into the narrowbore conduit means 27 after a pressure rise to prevent the elasticity of the diaphragm means 61 causing fluid to be sucked into the narrowbore conduit means 27 via the orifice means 65.

The advantage of the implementation shown in Figure 6 for an oil or gas well application is that it serves to ensure rapid as well as slow pressure change communication and also serves to prevent ingress of production fluids into narrowbore conduit means 27 that benefits from having within it a fluid of controlled quality.

The amount of fluid that may be pumped into the narrowbore conduit means 27 during a shut down test in an underpressurised oil well may be significant - for example a figure of approximately 15 litres per kilometre may be required if the narrowbore conduit means 27 is manufactured from ¼" hydraulic control line. In this instance it may be desirable to locate the flow preventor means 35 and the pressure communication means 30 at the very bottom of the oil well 20.

When the oil well 20 is allowed to flow again, the downhole pressure will drop, and fluid will drain into the production tubing 22 via the orifice means 65.

There is a danger that the orifice means 65 will fill with scale, corrode, or become blocked with production fluid. It may therefore be desirable to insert an additional fluid separator between the pressure communication means 30 and the production tubing 22 in order to minimise the amount of production fluid from entering the pressure communication means 30. Alternatively, the orifice means 65 may be designed such that it may be pumped down the narrowbore conduit means 27 and located in position as shown. Should it become blocked, it could be removed by over pressurising the narrowbore conduit means 27, and a replacement orifice means 65 pumped down the narrowbore conduit means 27.

An alternative method to reduce the volume requirement of the liquid buffer within the diaphragm means 61 is to pressurise the narrowbore conduit means 27 prior to a significant pressure increase at the measurement location 29. This relies on there being a low flow rate of liquid through the orifice means 65. The pressure

rise during well testing can then be deduced from the resulting pressure measurement from the second pressure gauge 2 by observing the rate of change of pressure. After the oil well 20 is shut in, the pressure in the narrowbore conduit means 27 and the production tubing 22 will equalise.

The flow preventor means 35 shown in Figure 3 may be implemented as part of the pressure communication means 30 such that it contains baffles 71 as shown in Figure 7. These baffles 71 induce higher pressure drops for the same flow rate thus allowing faithful pressure communication and assisting the ability to flush contaminants such as oil out of the flow preventor means 35 when required.

Figure 8 shows a further implementation of the invention where the first pressure gauge 1 measures the pressure within the narrowbore conduit means 27 using a capillary means 81. The capillary means 81 has gas flowed along it from a gas supply means 82. The implementation operates using the well known bubbler principle whereby the pressure required at the surface to cause bubbles to enter the liquid is a measure of the pressure at the exit of the capillary means 81. Techniques are well known to correct for the weight of the gas column.

The capillary means 81 may be of sufficient dimensions to be pumped along the narrowbore conduit means 27.

The capillary means 81 may resemble a silica optical fibre together with its coating. Suitable dimensions for the capillary means 81 may comprise a coated outer diameter less than 2.5mm, a glass outer diameter less than 250μm and an inner

diameter of greater than 25μm. More typically, the coated diameter would be 150μm, the glass outer diameter 125μm and the inner diameter 75μm. Such dimensions will permit pumping the capillary means 81 into practical hydraulic control lines as well as removing them from the hydraulic control lines should the capillary means 81 become blocked (for example with oil).

The gas used in the application is ideally dry nitrogen or dry helium.

In a typical application, the narrowbore conduit means 27 may be able to support a full column of liquid at the start of the reservoir's 21 life. The oil well 20 is called an overpressure well. The pressure in the reservoir 21 drops as hydrocarbon is extracted, and the narrowbore conduit means 27 is no longer is able to support a full column of liquid. The oil well 20 is then an underpressurised well.

The above system is capable of providing accurate measurements of pressure for both the overpressurised well and the underpressurised well.

For the underpressurised well, the liquid level will be within the narrowbore conduit means 27, and this liquid level will fall as the reservoir 21 is drained. The fall in the liquid level may be several thousand feet during the life of a typical reservoir. In this case, gas such as dry nitrogen or helium is pumped into the capillary means 81 until there is sufficient pressure to bubble gas into the liquid within the narrowbore conduit means 27. When the gas is just bubbling into the liquid, the pressure in the capillary means 81 corresponds to the pressure at its exit.

The pressure in the capillary means 81 can then be measured by the first pressure gauge 1 and output to the signal processing means 3.

For the overpressurised well, the liquid level in the narrowbore conduit means 27 is at or beyond the seal means 31. In other words, the capillary means 81 is able to communicate the pressure to the first pressure gauge 1 using the fluid in the narrowbore conduit means 27. In this case the pump 82 is not required, and the capillary means 81 may be filled with fluid by bleeding the narrowbore conduit means 27 at a suitable port. The pressure at the end of the capillary means 81 within the narrowbore conduit means 27 can be calculated from the hydrostatic head within the capillary means 81. Nevertheless, it is preferred to use dry gas in the capillary means 81.

The average pressure at the pressure communication means 30 is calculated from the pressure at the exit of the capillary means 81 and the hydrostatic head from the exit of the capillary means 81 and the pressure communication means 30. It will be noticed that correction algorithms for this pressure which take into account variations in fluid density owing to temperatures and pressure are known. These calculations are facilitated by means of the temperature profile within the narrowbore conduit means 27 which may be measured by a temperature profiling sensor such as the York DTS 80. The optical fibre for the temperature profiling sensor may be pumped through the narrowbore conduit means 27 in a similar

manner to the way in which the optical fibre pressure sensor 24 together with the associated cable 25 may be pumped through the narrowbore conduit means 27.

The capillary means 81 may be implemented by several different methods. For example, it may comprise a length of 1/8" or smaller hydraulic steel conduit which has been permanently installed into the narrowbore conduit means 27. The disadvantage for high-pressure wells is that the capillary means 81 may have to be very long and support very high pressures at the beginning of the life of an overpressurised well.

The capillary means 81 may also be silica capillary of dimensions similar to that of optical fibre cable (these have outer glass diameters of 125μm). The advantage here is that such a capillary can be pumped into the narrowbore conduit means 27 and repositioned as required by analogous techniques to those for pumping a fibre cable through the conduit. It will be noted that if the pressure in the reservoir 21 is being drained very slowly, then the downhole pressure before and after repositioning the capillary means 81 will, for all practical purposes, be identical. This fact may be used to remove uncertainties in the location of the capillary means 81.

In applications where the surface pressure in the narrowbore conduit means 27 is low, the capillary means 81 may be constructed from relatively low-pressure capillary tubing such as PTFE tubing.

The measured pressure from the first pressure gauge 1 will be a delayed measurement of the downhole pressure. This is because it takes time for the pressure to be communicated through the narrowbore conduit means 27 and through the capillary means 81 - the narrower bore the capillary, the longer it will take to communicate information. Moreover, the transmission of pressure information through the narrowbore conduit means 27 and the capillary means 81 is also dispersive - that is narrowbore conduit means 27 and the capillary means 81 will smooth out rapidly varying pressure information leading, in general, to loss of rapidly varying pressure information at high resolution. Unfortunately, this is precisely the information required by reservoir engineers during "shut-in tests" where the well is "shut in" (closed) and the pressure in the oil well 20 rises.

The longer the narrowbore conduit means 27, and the longer and narrower the bore in the capillary means 81, the greater the time lag in the measurement and the greater the effective time constant in the measurement.

The purpose of the signal processing means 3 is to combine the outputs from the first pressure gauge 1 and the second pressure gauge 2 in order to provide a single measurement of good stability and good dynamic response.

An example of the signal processing means is shown in Figure 9. Here the output of the second pressure gauge 2 is filtered with a high-pass filter 91 which is designed with a time constant equal to the time constant of the measurement from

the first pressure gauge 1. The resulting output provides a measurement of the downhole pressure.

It would be desirable in this and other related implementation to equalise the scale factor (or sensitivity) of the first pressure gauge 1 and the second pressure gauge 2 prior to summing their outputs.

A further example of the signal processing means is shown in Figure 10 where the output from the second pressure gauge 2 is filtered and delayed (in any order) before being summed with the output from the first pressure gauge 1. The delay time is matched to the delay of information through the narrowbore conduit means 27 and the capillary means 81. The resulting output has a latency corresponding to the delay time.

It should be noted that the above signal processing means maybe carried out using either analogue or digital techniques. These digital techniques may either use rapid sampling times or infrequent sampling times with the filtering process being performed very infrequently (eg once per month). Alternatively, the processing may be accomplished using optimal digital filtering techniques such as Kalman filters.

For measuring the pressures in horizontal wells, it would be advantageous to combine the features in some of the above embodiments. In particular, the flow restrictor means 35 shown in Figure 4, the optical pressure gauge 24 shown in Figure 2, and the capillary means 81 shown in Figure 8. Pressure would then be communicated along the horizontal section of production tubing 22 along the

narrowbore conduit means 27 which would be filled with liquid to at least the level of the capillary means 81 which would be located in the downward section of the production tubing 22. This combination removes the well understood short comings of conventional bubbler systems in horizontal applications.

It is to be appreciated that the embodiments of the invention described above with reference to the accompanying drawings have been given by way of example only and that modifications and additional components may be provided to enhance the performance of the apparatus.

Claims

1. Apparatus for combining two measurements of pressure where one measurement is obtained from a first pressure gauge having good long-term stability and a second pressure gauge having good dynamic response where the two measurements are combined in a signal processing means to provide a single measurement with good long-term stability and good dynamic response.

2. Apparatus according to claim 1 where the second pressure gauge is an optical pressure gauge where the optical pressure gauge and its associated cable interconnecting the optical pressure gauge with its associated readout electronics is of suitable dimensions to be pumped with fluid through a narrowbore conduit means to a remote location and where pressure is communicated from a measurement location to the optical pressure gauge via a pressure communication means.

3. Apparatus according to claim 2 where there is also provided a flow preventor means to restrict fluid from the measurement location flowing into the narrowbore conduit means.

4. Apparatus according to claim 3 where the flow preventor means contains a valve means and a second conduit means, where the second conduit means interconnects between the valve means and the narrowbore conduit means, and where the valve means is closed when the pressure in the second conduit means is sufficient to close the valve means.

5. Apparatus according to claim 3 where the flow preventor means contains a diaphragm means buffering the fluid in the measurement location from the fluid in the narrowbore conduit means, and where there is sufficient fluid in the diaphragm means to pressurise the narrowbore conduit means during a pressure build up in the measurement location, and where there is an orifice means interconnecting the measurement location and the narrowbore conduit means to communicate the pressure accurately during slow pressure changes.

6. Apparatus according to claim 3 where the flow preventor means contains baffles which induce higher pressure drops for the same flow rate thus allowing faithful pressure communication and assisting the ability to flush contaminants such as oil out of the flow preventor means when required.

7. Apparatus according to any of the above claims where the apparatus contains a capillary means which interconnects a measurement point within the narrowbore conduit means and the first pressure gauge, and where gas is injected through the capillary means according to the well-known bubbler principle.

8 Apparatus according to claim 7 where the capillary means is of sufficient dimensions to be pumped along the narrowbore conduit means.

9. Apparatus according to claim 8 where the capillary means has a coated outer diameter less than 2.5mm, a glass outer diameter less than 250μm and a inner diameter of greater than 25μm.

10. Apparatus according to claim 1 where the signal processing means may include a filter for removing the low frequency content from the second pressure gauge, and a summer for adding the resulting signal to the signal from the first pressure gauge.

11.. Apparatus according to claim 10 where the signal processing means may include a delay element for delaying the filtered signal from the second pressure gauge by an amount approximately equal to the time delay between a pressure change affecting the second pressure gauge and the first pressure gauge.

12. Apparatus for combining two measurements of pressure substantially as herein described with reference to the accompanying drawings.

The Patent Office

29.

Application No: GB 9619959.1
Claims searched: 1-12

Examiner: M. G. Clarke
Date of search: 27 January 1997

Patents Act 1977
Search Report under Section 17

Databases searched:

UK Patent Office collections, including GB, EP, WO & US patent specifications, in:

UK Cl (Ed.O): G1A AFH, APG; G1N NAHAX, NAHS

Int Cl (Ed.6): G01L 27/00

Other: -----------------

Documents considered to be relevant:

Category	Identity of document and relevant passage	Relevant to claims
X	US5311452 assigned to Tokyo Electron Limited - whole document	1 at least
X	US4339943 assigned to Smiths Industries Limited - whole document	1 at least

X	Document indicating lack of novelty or inventive step	A	Document indicating technological background and/or state of the art.
Y	Document indicating lack of inventive step if combined with one or more other documents of same category.	P	Document published on or after the declared priority date but before the filing date of this invention.
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